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10 CFR 50
10 CFR 51
10 CFR 54

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Three Mile Island Nuclear Station, Unit 1.
Facility Operating License No. DPR-50
<u>NRC Docket No.50-289</u>

Subject: Response to NRC Request for Additional Information related to Three Mile Island Nuclear Station, Unit 1, License Renewal Application.

Reference: Letter from Mr. Jay Robinson (USNRC), to Mr. Michael P. Gallagher (AmerGen) "Request for additional information for Appendix B, Aging Management Programs, of the Three Mile Island Nuclear Station, Unit 1, License Renewal Application", dated September 29, 2008. (TAC No. MD7701)

In the referenced letter, the NRC requested additional information related to Appendix B, Aging Management Programs, of the Three Mile Island Nuclear Station, Unit 1, License Renewal Application (LRA). Enclosed are the responses to this request for additional information.

Two of our responses resulted in changes to our commitments identified in Appendix A (A.5 commitment list), of the Three Mile Island Nuclear Station, Unit 1, License Renewal Application. These commitment changes are summarized within Enclosure B, Summary of Commitments.

If you have any questions, please contact Fred Polaski, Manager License Renewal, at 610-765-5935.

I declare under penalty of perjury that the foregoing is true and correct.

Respectfully,

Executed on 10 - 20 - 2008

Michael P. Gallagher
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Vice President, License Renewal
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A131
FDMC

Enclosure A: Response to Request for Additional Information for Appendix B, Aging Management Programs, of the Three Mile Island Nuclear Station, Unit 1, License Renewal Application.

Enclosure B: Summary of Commitments

cc: Regional Administrator, USNRC Region I, w/Enclosure
USNRC Project Manager, NRR - License Renewal, Safety, w/Enclosure
USNRC Project Manager, NRR - License Renewal, Environmental, w/o Enclosure
USNRC Project Manager, NRR - TMIGS, w/o Enclosure
USNRC Senior Resident Inspector, TMIGS, w/o Enclosure

File No. 08001

Enclosure – A

Response to Request for Additional Information for Appendix B, Aging Management Programs, of the Three Mile Island Nuclear Station, Unit 1, License Renewal Application.

Note: As a standard convention for AmerGen RAI responses, added text will be shown as ***bolded italics*** whereas deleted text will be shown as ~~strikethrough~~.

RAI#: B.2.1.1-1

LRA Section: B.2.1.1, American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection (ISI), Subsections IWB, IWC, and IWD

Background:

The first paragraph under "Exceptions to NUREG-1801", on Page B-13 of the License Renewal Application (LRA) states that "The next 120-month inspection interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval", indicating that the program will be in accordance with the Generic Aging Lessons Learned (GALL) Report (NUREG-1801, Rev. 1) during the period of extended operation.

Issue:

Since the code edition was previously approved under 10 CFR 50.55a for this ten-year interval, the staff concluded that the stated exceptions should not be identified as such. Similarly, the staff finds that an exception is not needed for requirements found in the 2001 edition, but not in the 1995 edition of the code.

Request:

Indicate agreement or provide justification if disagreement.

AmerGen Response

Amergen concurs that a formal exception to the ASME code version listed in NUREG-1801, Revision 1 is not required since the code edition used for the program, ASME 1995 Edition including the 1996 Addenda, has been previously approved under 10 CFR 50.55a for this ten year interval.

The elimination of this exception requires the following change to Section B.2.1.1, page B-13:

NUREG-1801 Consistency

The TMI-1 Inservice Inspection aging management program is an existing program that is consistent with NUREG-1801 aging management program XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD with the exceptions described below.

Exceptions to NUREG-1801

- ~~NUREG-1801 specifies the 2001 ASME Section XI B&PV Code, including the 2002 and 2003 Addenda for Subsections IWB, IWC, and IWD. The TMI-1 ISI Program Plan for the third ten-year inspection interval effective from April 20, 2001 through April 19, 2011, approved per 10CFR 50.55a, is based on the 1995 ASME Section XI B&PV Code, including 1996 addenda. The next 120-month inspection interval for TMI-1 will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.~~

RAI#: B.2.1.1-2

LRA Section: B.2.1.1, ASME Section XI ISI, Subsections IWB, IWC, and IWD

Background:

Page I-2 of the GALL Report, Volume 2, Revision 1 states the following on the applicability of current Code reliefs for the period of extended operation:

> "The NRC Director of the Office of Nuclear Reactor Regulation may approve licensee proposed alternatives to the ASME Code in accordance with the provisions of 10 CFR 50.55a(a)(3). These NRC approved ASME Code alternative requirements may have an associated applicability time limit. The applicability time limits associated with the approved alternatives do not extend beyond the current license term. If an applicant seeks relief from specific requirements of 10 CFR 50.55a and Section XI of the ASME Code for the period of extended operation, the applicant will need to re-apply for relief through the 10 CFR 50.55a relief request process once the operating license for the facility has been renewed."

Issue:

The staff noted the use of risk informed inservice inspection (RI-ISI) to determine inspection frequency. RI-ISI and the use of specific Code Cases have been approved by the NRC under the 10 CFR 50.55a process and only apply to the current ISI interval. The provisions of 10 CFR 54 for the license renewal process do not include the use of ASME Section XI code cases or RI-ISI. The staff noted that the fourth inspection will be performed during the period of extended operation and that the program will be submitted during the current license period for the fourth ISI interval.

Request:

How will the TMI-1 ISI program be implemented during the period of extended operation? Explain if TMI-1 will follow ASME Code requirements and approved code cases as described in Regulatory Guide 1.147 for future intervals.

AmerGen Response

The current (third) ten-year Inservice Inspection (ISI) interval includes relief requests from code requirements that have been authorized or granted per NRC SERs. For each of these approved relief requests, the applicable period for relief is the third ten-year inspection interval, which is effective from April 20, 2001 through April 19, 2011. The third ten-year inspection interval also includes the application of selected ASME Section XI Code Cases approved by 10 CFR 50.55a and NRC Regulatory Guide 1.147. TMI-1 will continue to follow code inspection requirements during the fourth ten-year ISI interval, which will begin April 20, 2011 (and would extend into the period of extended operation beginning in April 2014), applying for any necessary relief requests in accordance with the requirements of 10 CFR 50.55a and invoking selected code cases approved in Regulatory Guide 1.147. At the time of the period of extended operation, TMI-1 will comply with NRC requirements for any necessary relief requests and approved code cases for the fourth ten-year ISI interval that extend into the period of extended operation.

RAI#: B.2.1.2-1

LRA Section: B.2.1.2 Water Chemistry

Background:

The staff noted the following differences between TMI-1's implementing procedures for AMP B.2.1.2, "Water Chemistry", and recommendations in Electric Power Research Institute (EPRI) Topical Report (TR)-1002884, "Pressurized Water Reactor Primary Water Chemistry Guidelines", Revision 5:

Differences in Actions Limits (AL)						
Parameter	EPRI Guideline			TMI-1 Procedure		
	AL1	AL2	AL3	AL1	AL2	AL3
Dissolved Oxygen (pps)	>5	-----	>100	>5	>100	>1000

Differences in Sampling Frequencies		
Parameter	EPRI Guideline	TMI-1 Procedure
Conductivity	1/D (once per day)	5/W (five per week)
PH	1/D	5/W
Boron	1/D	2/W

Request:

1. For the differences in action limits and sampling frequencies noted above, explain why these differences are not considered to be exceptions to the recommendations of the GALL Report, which states that a pressurized water reactor (PWR) applicant's primary water chemistry program should be based on EPRI TR-105724, "PWR Primary Water Chemistry Guidelines", Revision 3, or later revisions.

2. Provide technical justification as to why the differences between the TMI-1 program's parameters and the recommendations in the EPRI guidelines are acceptable to provide adequate protection for components affected by primary water chemistry.

AmerGen Response

1. TMI-1 has implemented Revision 6 of the EPRI PWR Water Chemistry Guidelines 1014986, dated December 2007. The bases for the differences identified between the TMI-1 action limits and sampling frequencies and those included in EPRI Guidelines are as follows:

   a. Dissolved Oxygen — The TMI-1 water chemistry action limits for dissolved oxygen are consistent with the EPRI Guidelines, as shown in the table below. Therefore, the

Comparison of Dissolved Oxygen Action Limits (AL)						
Parameter	EPRI Guideline, Rev 6			TMI-1 Procedure		
	AL1	AL2	AL3	AL1	AL2	AL3
Dissolved Oxygen (pps)	>5	>100	>1000	>5	>100	>1000

recommendation of the GALL Report is met without exception.

b. pH — The sampling of pH was eliminated from Table 3-4 of the EPRI Guidelines. Therefore, the sampling frequency for pH utilized at TMI-1 is not inconsistent with current EPRI Guidelines and is not an exception to the GALL Report.

c. Conductivity and Boron — Table 3-4 of the EPRI Guidelines identifies conductivity and boron as diagnostic parameters. EPRI considers the sampling of diagnostic parameters as a recommended element, as defined by NEI 03-08, and allows sampling frequencies for these parameters based on individual plant needs. Therefore, the TMI-1 sampling frequencies of five times per week for conductivity and two times per week for boron are consistent with the EPRI Guidelines and the GALL Report is met without exception.

2. The technical justification for the differences between the TMI-1 Water Chemistry Program requirements for monitoring of reactor coolant system boron and conductivity and the recommendations in the EPRI guidelines, Revision 6, is as follows:

   a. Boron — Table 3-4 of the EPRI Guidelines recommends that boron analysis be performed once per day. However, footnote 2 of the table clarifies that boron analysis should be performed as required by Technical Specifications or as needed by plant operators. TMI-1 boron analysis, performed two times per week per Technical Specification Table 4.1-3, Minimal Sample Frequency, is adequate for reactivity control. During plant transients, boron is measured more frequently to ensure that reactor coolant boron concentration values are available for reactivity analysis. Performing boron analysis two times per week meets the intent of the EPRI Guidelines for diagnostic parameters.

   b. Conductivity — Table 3-4 of the EPRI Guidelines recommends that conductivity be measured daily as a diagnostic parameter to assess consistency with expected system chemistry. Common contaminant concentrations have minimal impact on conductivity. For example, the change in conductivity between normal chloride levels and the Action Level 1 limit is only 0.15 uS/cm. This demonstrates that the change in conductivity due to realistic variations in contaminants, such as chloride, is small. Therefore, in the presence of boron, lithium, and ammonia, detecting intrusion of common contaminates with conductivity is of low probability.

      Due to the limited value of conductivity when identifying contaminant levels, measuring specific conductivity five times per week is deemed adequate and meets the intent of the EPRI Guidelines for diagnostic parameters.

Based on the discussion above, the TMI-1 water chemistry program is consistent with the EPRI Guidelines and provides adequate protection for components affected by primary water chemistry.

RAI#: B.2.1.4-1

LRA Section: B.2.1.4, Boric Acid Corrosion

Background:

The Gall Report AMP (XI.M10) addressing Boric Acid Corrosion (BAC) provides for the management of loss of material due to boric acid corrosion.

Issue:

The specific components included within the scope of the BAC AMP could not be determined. It was unclear whether or not examinations will be implemented through the BAC AMP or a different AMP for in-scope nickel alloy locations. It was unclear as to which program would be used to evaluate evidence of leakage that is detected through the BAC or another AMP. For in-scope nickel alloy components it was unclear as to what type of visual examinations will be performed.

Request:

1. Clarify which components are included within the scope of the BAC Program AMP, and whether the scope includes all Class 1 nickel alloy locations.

2. For in-scope nickel alloy locations (if any), clarify whether the examinations will be implemented through the BAC AMP or some other TMI-1 AMP in the LRA. If another AMP will be used for specific components, clarify which AMP will be implemented for the examination.

3. Clarify which programs will be used to evaluate the evidence of leakage that is detected through this AMP or other AMPs.

4. For the in-scope nickel-alloy components, clarify what type of visual examinations (i.e., specify whether VT-1, VT-2 or VT-3, and whether the visual examinations are enhanced, bare-surface, qualified, etc.) will be performed on the components.

AmerGen Response

1. Components and structures included in the scope of the Boric Acid Corrosion program, B.2.1.4, are all components from which borated water can leak (source) and all components and structures within the vicinity of potential borated water leakage (target). This includes all components within the Reactor, Auxiliary, and Fuel Handling Buildings. Class 1 nickel alloy components located in these buildings are included in the scope of this program.

2. Visual inspections are performed under the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program, B.2.1.5 and the Nickel-Alloy Aging Management Program, B.2.2.1. Both of these programs and the Boric Acid Corrosion program direct inspections; however, evaluations of borated water leakage are performed under the Boric Acid Corrosion program.

3. Evaluations of borated water leakage, regardless of which AMP detected the leak, are performed under the Boric Acid Corrosion program.

4. Visual examinations (VE) of nickel-alloy components are performed under the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors program, B.2.1.5 and the Nickel-Alloy Aging Management Program, B.2.2.1 by VT-2 qualified personnel. These examinations are consistent with the requirements of 10 CFR 50-55a and visual examination recommendations of Code Cases N-722 and N-729-1. The visual examination requirements of N-722 and N-729-1 are as follows: (a) direct bare-metal surface inspections with insulation removed or with insulation in place by using remote visual inspection equipment that provides resolution of the component metal surface equivalent to a bare metal VE, (b) VE may be performed when the system or component is depressurized, and (c) VE is performed at a distance not greater than 4 ft from the component and with a demonstrated illumination level sufficient to allow resolution of lower case characters having a height of not greater than 0.105 in.

RAI#: B.2.1.6-1

LRA Section: B.2.1.6, Flow Accelerated Corrosion

Background:

The GALL Report AMP XI.M17 relies on implementation of the EPRI guidelines NSAC-202L-R2 for an effective Flow Acceleration Corrosion (FAC) program. On page B-27 of the LRA, there is an exception that states NSAC-202L-R3 is used and that Rev. 2 and Rev. 3 of the guidelines are equivalent with one difference: Rev. 3 allows an additional method, (Averaged Band Method), for determining the wear of piping components from ultrasonic examination (UT) which TMI-1 does not use at this time.

Issue:

The program basis document references procedure ER-AA-430, "Conduct of Flow Accelerated Corrosion Activities", which utilizes NSAC-202L-R2 as a guideline.

Request:

1. Clarify if TMI-1 plans to revise procedure ER-AA-430 to include NSAC-202L-R3 instead of NSAC-202L-R2?
2. Indicate if TMI-1 has any plans to use the Averaged Band Method for determining the wear of piping components from UT in the future, and if so, what additional controls will be put in place to utilize this method.

AmerGen Response

1. The TMI-1 Flow Accelerated Corrosion aging management program will rely on the implementation of EPRI guideline NSAC-202L-R3. TMI-1 Flow Accelerated Corrosion aging management program implementing procedure ER-AA-430 will be revised to identify that the program is in accordance with EPRI guideline NSAC-202L-R3.
2. At the time of the development of the TMI-1 Flow Accelerated Corrosion aging management program and submittal of the TMI-1 LRA, there was no plan to implement the Averaged Band Method for determining the wear of piping components from UT. The exception in the TMI-1 Flow Accelerated Corrosion aging management program involving the implementation of NSAC-202L-R3 identified that the Averaged Band Method would not be implemented for TMI-1.

   The TMI-1 Flow Accelerated Corrosion aging management program is currently transitioning to allow the use of the Averaged Band Method for determining the wear of piping components from UT inspection as described in NSAC-202L-R3. The TMI-1 Flow Accelerated Corrosion aging management program implementing procedures will allow for the use of the Averaged Band Method for determining the wear of piping components from UT.

   The LRA Appendix B.2.1.6 exception to GALL AMP XI.M17 should have read:

NUREG-1801 specifies in XI.M17 that the program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective FAC program. The TMI-1 FAC Program is based on the EPRI guidelines found in NSAC-202L-R3. The sections of NSAC-202L associated with the program elements were reviewed to show that revision 2 and 3 of the guidelines are equivalent with one difference: revision 3 allows an additional method for determining the wear of piping components from UT inspection. This method is called the Averaged Band Method. ~~TMI-1 does not use this method at this time.~~ ***This method is a derivation of the Band Method and builds upon the years of experience with the Band Method, which remains an option in NSAC-202L-R3 for determining the wear of piping components from UT inspection. Overly conservative methods can lead to unnecessary inspections or re-inspections. The Averaged Band Method provides a more accurate and less conservative estimate of piping wear than the Band Method.***

RAI#: B.2.1.6-2

LRA Section: B.2.1.6, Flow Accelerated Corrosion

Background:

The GALL Report AMP XI.M17 in the "monitoring and trending" element recommends that inspection results be evaluated to determine if additional inspections are needed.

Issue:

It is not clear what criteria is used to determine when additional samples are required.

Request:

Provide the criteria used to determine when additional samples are required.

AmerGen Response

In accordance with the TMI-1 Flow Accelerated Corrosion aging management program implementing procedures, if any component has a current or projected wall thickness within the next operating cycle that is less than the minimum acceptable wall thickness, or if any component exhibits unexpected wall thinning, then sample expansion is required to bound the area of thinning. Sample expansion is not required if the thinning was expected or if the thinning is unique to that component (e.g., degradation downstream of a leaking valve).

Initial sample expansion inspections consist of the following:

- Any component within two pipe diameters downstream of the degraded component and within two diameters upstream if that component is an expander or expanding elbow.
- The two highest ranked components from the EPRI developed software "CHECWORKS" wear rate predictions, from the train in which the degraded component is modeled.
- Components of similar geometry in sister trains.

If the initial sample expansion inspections detect components with significant wear, then the inspection scope is further expanded to include the following:

- Any component within two pipe diameters downstream of the degraded component or within two diameters upstream if that component is an expander or expanding elbow.
- The two highest ranked components from the EPRI developed software "CHECWORKS" wear rate predictions from the train in which the degraded component is modeled that have not been previously inspected.

If the further expanded inspection scope detects additional degradation, the sample expansion is continued until no additional components with significant wear are detected.

RAI # B.2.1.9-1

LRA Section: B.2.1.9, Open-Cycle Cooling Water System

Background:

On page B-37 of the LRA, exceptions to the GALL Report for the Open-Cycle Cooling Water System AMP are identified. The exception states that the AMP activities are adequate for managing the aging effects of the internal surfaces of concrete circulating water piping.

Issue:

Based on the information provided, the adequacy of the Open-Cycle Cooling Water System program to provide adequate aging management for this concrete component, which is treated as a structure in the LRA when documenting the aging management review results cannot be completed.

Request:

1. Is inspection or monitoring of the concrete circulating water piping currently included in the Open-Cycle Cooling Water System program, and are current base-line conditions for this component/structure known and documented? Provide a description of current conditions, if known.

2. On what frequency is the condition of the concrete circulating water piping inspected? Is the inspection mandatory or optional? What is the extent (percentage coverage) of the inspection? What is the basis for any inspection frequency requirement?

3. The LRA lists several aging effects/mechanisms for the internal surface of the concrete circulating water piping accounted for in the Open-Cycle Cooling Water System AMP. For each of the aging effects/mechanisms listed in the LRA, provide a description of the examination techniques used to detect the aging effects, if present. Also, provide the history of aging effects previously detected, and the history of any corrective actions previously taken.

AmerGen Response

1. The TMI-1 Open-Cycle Cooling Water Aging Management Program credits the internal walkdown and inspections of the concrete circulating water piping and tunnels for License Renewal. The current conditions of the piping and tunnels are known and have been documented including photographs. Inspections performed during the Fall 2003 refuel outage identified degraded caulking at seven piping joints. Inspections performed during the Fall 2005 refuel outage identified no significant increase in degradation at these joints and no degradation in other locations throughout the concrete piping and tunnels. The most recent inspections were performed during the Fall 2007 refuel outage. These inspections identified degraded caulking and minor degradation, including loss of material (corrosion), at two of the previously identified degraded joints and at seven additional piping joints. The conditions of the degraded joints are documented and planned repairs are tracked in the TMI-1 Corrective Action Program.

No other degradation has been identified throughout concrete circulating water piping and tunnels.

Re-inspection of the concrete piping and tunnels, including the previously identified degraded piping joints, will be performed during the refuel outage in Fall 2009. Repairs will be performed as necessary.

Note that the TMI-1 Structures Monitoring Program (B.2.1.28) also credits the walkdown and inspection of the concrete circulating water piping and tunnels. Internal inspection of the circulating water concrete tunnels, which requires drainage of the circulating water system, is required by the TMI-1 Structures Monitoring Program every five years. Aging effects managed by this program are addressed in the response to RAI # 2.4.16-2.

2. Internal inspection of the circulating water piping credited by the Open Cycle Cooling Water System Aging Management Program is currently an optional inspection performed when the circulating water system is drained. The system is drained to perform desilting of the cooling tower basins, which is typically performed every refuel outage. This activity includes walkdown and general visual examination of the entire length of the piping and tunnels between the main circulating water pump discharge and the main condenser inlet and between the main condenser outlet and the natural draft cooling towers. The inspection scope includes 100% coverage of both system trains. The inspection frequency is based on the need to drain the piping and tunnels prior to inspection, which normally occurs only during refuel outages.

3. General visual examination will be utilized for detection of all aging mechanisms identified in the LRA for the internal surfaces of the concrete circulating water piping and tunnels. Aging mechanisms identified during past inspections of the piping and tunnels include loss of material (corrosion) associated with degraded caulking at piping joints. These aging mechanisms were identified through general visual examination. Repairs are planned for the degraded joints as discussed in the response to Request #1. Review of maintenance history from 2003 to present identified no repairs of the circulating water piping or tunnels performed in that time period.

RAI#: B.2.1.12-1

LRA Section: B.2.1.12, Compressed Air Monitoring Program

Background:

The GALL Report AMP XI.M24, Compressed Air Monitoring, states that the program manages the effects of corrosion and presence of unacceptable levels of contaminants on the intended function of the compressed air system.

Issue:

On page B-47 of the LRA, the program description states that the Compressed Air Monitoring Program manages loss of material due to corrosion and reduction of heat transfer due to fouling.

Request:

Explain how this program manages the effects of fouling and the resulting reduction of heat transfer.

AmerGen Response

Maintenance is performed on the Instrument Air Aftercoolers, IA-C-1A and IA-C-1B, every four years. During this maintenance the aftercoolers are disassembled and inspected for a number of attributes including: corrosion, scaling or pitting; slime or other coating on the tubes; the presence of silt or debris; and other forms of fouling. If any discrepancies are identified, Issue Reports are initiated and the appropriate corrective actions are implemented. This process of maintenance and inspection of the aftercoolers manages the effects of fouling and the resulting reduction of heat transfer.

RAI#: B.2.1.12-2

LRA Section: B.2.1.12, Compressed Air Monitoring Program

Background:

The GALL Report AMP XI.M24 in the "monitoring and trending" element states that test data are analyzed and compared to data from previous tests to provide for timely detection of aging effects.

Issue:

The program basis document (TM-PBD-AMP-B.2.1.12, Revision 1, "Compressed Air Monitoring") for this element states that results of tests are compared to established acceptance criteria; however, it is not clear if these results are compared to previous test results to establish a trend.

Request:

Clarify and discuss if the test results are also compared to previous test results for trending purposes.

AmerGen Response

The Station Procedure, ER-AA-2030, Conduct of Plant Engineering Manual requires the system manager to maintain a System Notebook that contains current and historical performance data, and analysis results on the system, program, or components in the system. The system manager trends the previous data along with the current data to identify adverse trends or reductions in margin that may be indicative of aging.

RAI#: B.2.1.13-1

LRA Section: B.2.1.13, Fire Protection Program

Background:

The GALL Report AMP XI.M26, Fire Protection, in the "detection of aging effects" element, states that Halon/CO_2 system visual inspection detects any sign of degradation, such as corrosion, mechanical damage, or damage to dampers.

Issue:

The program basis document TM-PDP-AMP-B.2.1.13, Revision 1, "Fire Protection", references surveillance procedures 1303-12.11 for Halon system inspection and 1303-12.5 for CO_2 system inspection. However, the inspection procedures do not clearly state that the systems should be specifically inspected for corrosion, mechanical damage or damage to dampers.

Request:

Since surveillance procedures 1303-12.11 and 1303-12.5 do not do not provide for inspections for corrosion, mechanical damage, or damage to dampers, provide clarification as to why there is no enhancement to the Fire Protection AMP to provide for these inspections.

AmerGen Response

The requirement for visual inspection of the Halon and CO_2 systems to detect any sign of degradation such as corrosion, mechanical damage, or damage to dampers does not require an enhancement to the TMI-1 Fire Protection Program because these inspections are currently directed by the program. As stated in the program basis document, TM-PBD-AMP-B.2.1.13, "Fire Protection," the fire protection aging management program directs Halon and CO_2 fire suppression system surveillance that verifies system operation, including associated dampers, and identifies any adverse conditions such as corrosion, broken or missing parts, loose fasteners, excessive dirt or debris, or other degrading condition for corrective action evaluation.

Implementing Surveillance Procedure 1303-12.11, "Halon System Tests," states that conditions that could adversely affect equipment operation such as broken or missing parts and loose hardware, or material condition such as excessive dirt or debris, shall be evaluated for corrective action. It further states that the Halon containers are to be inspected for corrosion or mechanical damage. Clarifying reinforcement will be provided in this implementing surveillance procedure assuring inspection specifically for the NUREG-1801, Revision 1 aging mechanisms of corrosion, mechanical damage, or damage to dampers. This clarifying reinforcement will be added prior to entering the period of extended operation.

Implementing Surveillance Procedure 1303-12.5, "CO_2 Fire Protection System Test," states that any conditions that could affect equipment or system operation, or material condition such as broken or missing parts, loose nuts, bolts, or screws, excessive dirt or debris, or any other degrading condition be evaluated for corrective action measures. Clarifying reinforcement will be provided in this implementing surveillance procedure assuring inspection specifically for the NUREG-1801, Revision 1 aging mechanisms of corrosion, mechanical damage, or damage to dampers. This clarifying reinforcement will be added prior to entering the period of extended operation.

These clarifications to be added to the implementing procedures are not considered enhancements to the program since the program currently directs inspection for any adverse conditions such as corrosion, broken or missing parts, loose fasteners, excessive dirt or debris, or other degrading condition.

As a result of these additions to the implementing procedures, the Appendix A, A.5 License Renewal Commitment List, Item 13, Fire Protection, Commitment statement changes as follows:

> Existing program is credited. The program will be enhanced to include additional inspection criteria for degradation of fire barrier walls, ceilings, and floors, and specific fuel supply line inspection criteria for diesel-driven fire pumps during tests. ***In addition, implementing surveillance procedures for halon and carbon dioxide suppression systems will specifically require inspection for corrosion, mechanical damage, or damage to dampers, and will include acceptance criteria stating that detected signs of corrosion or mechanical damage be evaluated, with corrective action taken as appropriate.***

RAI#: B.2.1.13-2

LRA Section: B.2.1.13, Fire Protection Program

Background:

The GALL Report AMP XI.M26, Fire Protection, in the "acceptance criteria" element states any signs of corrosion and mechanical damage of the halon/carbon dioxide fire suppression system are not acceptable.

Issue:

There are no acceptance criteria specified for inspection parameters in surveillance procedures 1303-12.11 and 1303-12.5 that are referenced in the fire protection program basis document (TM-PDP-AMP-B.2.1.13, Revision 1, "Fire Protection") for Halon and CO_2 systems.

Request:

Provide clarification as to why there is no enhancement to the Fire Protection Program for acceptance criteria for the inspection of these system components.

AmerGen Response

Enhancement to the TMI-1 Fire Protection Program for halon and carbon dioxide systems inspection acceptance criteria for corrosion and mechanical damage is not required because such program acceptance criteria currently exists. As stated in the Acceptance Criteria section of program basis document, TM-PBD-AMP-B.2.1.13, "Fire Protection," the fire protection aging management program directs Halon and CO_2 fire suppression system surveillance that identifies any adverse conditions such as corrosion, broken or missing parts, loose fasteners, excessive dirt or debris, or other degrading conditions for corrective action evaluation. These inspections are performed through implementing Surveillance Procedures 1303-12.11, "Halon System Tests," and 1303-12.5, "CO_2 Fire Protection System Test."

The Limits and Precautions sections of these implementing surveillance procedures currently state that detection of any of these conditions require evaluation for corrective action. The Acceptance Criteria sections of these implementing surveillance procedures will be clarified to state specifically that the results of inspections for corrosion and mechanical damage be evaluated, with corrective action taken as appropriate. This clarification will be added prior to entering the period of extended operation.

This clarification to be added to the implementing procedures is not considered an enhancement to the program since the program currently states that any detected corrosion, broken or missing parts, loose fasteners, excessive dirt or debris, or other degrading conditions be evaluated for appropriate corrective action.

As a result of these additions to the implementing procedures, the Appendix A, A.5 License Renewal Commitment List, Item 13, Fire Protection, Commitment statement changes as follows:

> Existing program is credited. The program will be enhanced to include additional inspection criteria for degradation of fire barrier walls, ceilings, and floors, and specific

fuel supply line inspection criteria for diesel-driven fire pumps during tests. ***In addition, implementing surveillance procedures for halon and carbon dioxide suppression systems will specifically require inspection for corrosion, mechanical damage, or damage to dampers, and will include acceptance criteria stating that detected signs of corrosion or mechanical damage be evaluated, with corrective action taken as appropriate.***

RAI #: B.2.1.14-1

LRA Section: B.2.1.14, Fire Water System

Background:

The GALL Report AMP XI.M27, Fire Water System, in the "acceptance criteria" element, states that no biofouling exists in the sprinkler systems that could cause corrosion in the sprinkler heads.

Issue:

In the fire water system program basis document TM-PDP-AMP-B.2.1.14, Revision 1, "Fire Water System", section 3.6 (c) states that new inspection activities will include an evaluation of identified degradation for impact on the system or component intended functions. The applicant indicated during the on-site audit that non-intrusive (e.g., volumetric) testing techniques such as ultrasonic testing would be used.

Request:

Please clarify what information UT will provide that will enable an evaluation of fouling to be conducted.

AmerGen Response

The volumetric non-intrusive examination activities are intended to identify evidence of loss of material due to corrosion. The activities include an evaluation of identified degradation for impact on the system or component intended functions. In accordance with the corrective action process for deficiencies determined to be significantly adverse to quality, the cause of the condition is determined. The aging effect of loss of material can be caused by the aging mechanism of fouling. Fouling would therefore be considered and evaluated as a potential cause of loss of material in fire service piping. Volumetric examinations do not directly determine fouling as an aging mechanism; however, they provide evidence of the aging effect of loss of material that may result from the aging mechanism of fouling.

RAI #: B.2.1.14-2

LRA Section: B.2.1.14, Fire Water System

Background:

The GALL Report AMP XI.M27, Fire Water System, in the "preventive actions" element, states to ensure no significant corrosion, microbiologically influenced corrosion (MIC), or biofouling has occurred in water-based fire protection systems; periodic flushing, system performance testing, and inspections are conducted.

Issue:

The staff noted that Issue Report 748645 was issued on April 11, 2008 to document corrosion and possibly leakage of fire protection piping. The cause was determined to be heavy tuberculation of MIC causing excessive internal pitting. Issue Report 635626 indicates that ineffective mitigation of MIC in fire service water system has resulted in degradation of important piping, including some through wall leaks.

In section 3.2 of program basis document TM-PDP-AMP-B.2.1.14, Revision 1, "Fire Water System", it is stated that flow tests are conducted once every three years and that the flow tests are intended to evaluate for indication of internal piping degradation or fouling, but based on the above Issue Report, these periodic flow tests may not be adequate.

Request:

Please identify what preventive measures besides periodic flow testing are proposed to ensure that aging degradation due to MIC is adequately managed during the period of extended operation such that component intended functions are maintained.

AmerGen Response

Preventive measures to ensure that aging degradation due to MIC is adequately managed include periodic flushing, system performance testing, and inspections, as recommended in NUREG-1801, Revision 1, Program XI.M27 Fire Water System, Section 3.2, Preventive Actions. In accordance with TMI-1 station procedures, the fire water system main header is flushed at least once per 12 months. Fire water system deluge and sprinkler systems located in clean areas are flushed once per 18 months, and in radiation control areas are flushed once per refueling. A flow test of the system is performed at least once per three years in accordance with NFPA recommendations. Inspection activities include initiation of new periodic non-intrusive fire protection piping wall-thickness measurements. Evaluation of any identified degradation determined to be significantly adverse to quality includes a determination of cause, where MIC would be considered as a mechanism for loss of material.

In addition, chemical treatment of circulating water and river water to control biofouling has been recently implemented at TMI-1. Circulating water chemical treatment has been in use for approximately 5 years, and river water chemical treatment has been in use for approximately 1 year. Implementation of the new circulating water chemistry plan has significantly reduced the number of new MIC leaks per year in circulating water piping. Chemically treating these water supplies for the Fire Water System should reduce occurrences of MIC in fire service piping and components.

In accordance with the corrective action process, the fire service piping addressed by Issue Reports 748645 and 635626 is undergoing replacement and is scheduled for completion in 2008.

<u>RAI#: B.2.1.15-1</u>

LRA Section: B.2.1.15, Aboveground Steel Tanks

Background:

The program description on page B-57 of the LRA states that the program will provide for management of loss of material aging effects for outdoor carbon steel tanks.

Issue:

Row 13 of LRA Table 3.2.2-5 on page 3.2-80, for component type "Sodium Thiosulfate Tank" and material type "stainless steel", credits AMP B.2.1.15 for aging management.

Request:

1. Clarify whether or not any stainless steel tanks, including the Sodium Thiosulfate Tank, are within the scope of AMP B.2.1.15.

2. Clarify whether or not stainless steel tanks will require a one-time thickness measurement of the bottom of the tanks.

<u>AmerGen Response</u>

1. The Aboveground Steel Tanks program manages only carbon steel tanks. LRA Table 3.2.2-5 incorrectly credited the Aboveground Steel Tanks program for managing loss of material of the Sodium Thiosulfate Tank, which is constructed of stainless steel. Table 3.2.2-5 should have credited External Surfaces Monitoring, B.2.1.21 for managing the external surfaces of the Sodium Thiosulfate Tank, not Aboveground Steel Tanks, B.2.1.15. Note 11 should have read:

   The aging effects of stainless steel in an air-outdoor (external) environment include loss of material due to pitting and crevice corrosion. These aging effects/mechanisms are managed by the ~~Aboveground Steel Tanks~~ ***External Surfaces Monitoring*** Program.

2. The Aboveground Steel Tanks program manages only carbon steel tanks. Additionally, the Sodium Thiosulfate Tank, which is the only outdoor stainless steel tank that is in scope for license renewal, is not supported by either an earthen or concrete foundation. One-time thickness measurements are only required on the bottom surfaces of those tanks supported by either an earthen or concrete foundation; therefore, no stainless steel tanks require a one-time thickness measurement.

RAI#: B.2.1.15-2

LRA Section: B.2.1.15, Aboveground Steel Tanks

Background:

On page B-58 of the LRA, as part of the enhancement, it is stated that the program will be enhanced to inspect the condition of the sealant between the Condensate Storage Tanks (CST) and the concrete foundations.

Issue:

Upon review of the Aging Management Review (AMR) line items in LRA Section 3, it does not appear that AMP B.2.1.15 accounts for aging management of paints and coatings on the external surface of the tanks, and sealants and caulkings at the tank-foundation interface of those tanks.

Request:

1. Clarify if the CSTs are the only tanks within the scope of this program that are supported by a concrete foundation with a sealant at the tank-foundation interface.

2. Clarify whether or not paints/coatings used on the external surface of the tanks and sealants/caulking used at the tank-foundation interface will be inspected as part of AMP B.2.1.15. If not, please indicate the program that is credited for aging management of paint/coatings on the external surface and sealants and caulkings at the tank-foundation interface.

AmerGen Response

1. The Condensate Storage Tanks (CSTs) are the only tanks managed by this program that are founded on a concrete foundation with a sealant at the tank-foundation interface.

2. The Aboveground Steel Tanks program, B.2.1.15 directs inspections for signs of paint/coating degradation (e.g., blistering, peeling, cracking), because signs of coating degradation could indicate underlying surface corrosion. The program also inspects sealants and caulking around the bottom of the CSTs to ensure moisture is not entering the interface between the bottom of the CSTs and their foundations. Without moisture, loss of material will not occur. Paints/coatings and sealants/caulking are considered design features that are used as a preventative measure, but they do not perform any intended function and are not in scope for License Renewal. As stated in LRA Section B.2.1.15, the program "performs periodic visual inspections to monitor degradation of the paint and any resulting metal degradation for the carbon steel tanks... The Condensate Storage Tanks are supported by concrete foundations and have sealant at the tank-foundation interfaces which will be periodically inspected for degradation."

RAI#: B.2.1.15-3

LRA Section: B.2.1.15, Aboveground Steel Tanks

Background:

On page B-57 of the LRA, an exception is taken which states that the program utilizes tank inspection at least every five years in place of periodic system walkdowns each outage. The exception further states that the change in frequency is based on industry guidance and experience that indicates that monitoring of exterior surfaces of components made of carbon steel with a protective coating on a frequency of at least every five years provides reasonable assurance that loss of material will be detected before an intended function is affected.

Issue:

The program element, "monitoring and trending", of the GALL Report AMP XI.M29, states that operating experience has shown that periodic walkdowns during each outage will provide timely detection of aging effects.

Request:

1. Clarify the current inspection frequency of all the tanks that are within the scope of this program.
2. Provide the details of the industry guidance and experience that is referred to in the exception and justify your basis for not performing walkdowns of these tanks each outage as recommended by the GALL Report.

AmerGen Response

1. As stated in LRA Section B.2.1.15, the inspection frequency for all of the tanks within the scope of the Aboveground Steel Tanks program is five years.
2. The five year frequency for monitoring the external surfaces of aboveground steel tanks is consistent with the frequency specified in TMI-1 Structures Monitoring Program, B.2.1.28 for the inspections of the external surfaces of the tanks' supporting structures. The five year frequency, which is consistent with industry guidelines as stated in SAND96-0343, Aging Management Guideline for Commercial Nuclear Power Plants – Tanks and Pools, has proven effective in detecting loss of material due to corrosion before loss of intended function can occur. Plant operating experience, as documented in LRA Section B.2.1.15, confirms the five-year inspection interval successfully identifies loss of material on the external surfaces of the applicable tanks at TMI-1 before loss of intended function can occur. Furthermore, the staff has accepted the 5-year inspection intervals for the Oyster Creek Generating Station as stated in Section 3.0.3.2.18 of NUREG-1875, Vol. 2, Safety Evaluation Report Related to the License Renewal of Oyster Creek Generating Station, Docket No. 50-219.

<u>RAI#: B.2.1.16-1</u>

LRA Section: B.2.1.16, Fuel Oil Chemistry

Background:

On page B-59 of the LRA it is stated that TMI-1 has not adopted the Standard Technical Specifications; however, the TMI-1 fuel oil specifications and procedures invoke equivalent requirements for fuel oil purity and fuel oil testing as described in the Standard Technical Specifications.

Issue:

The staff noted that the meaning of "equivalent requirements" is not clear.

Request:

Provide a direct comparison between the Standard Technical Specifications and the TMI-1 fuel oil specifications along with a justification for any difference in fuel oil purity and testing parameters.

<u>AmerGen Response</u>

NUREG-1801 states in XI.M30 "Fuel Oil Chemistry", Element 1 "Scope of Program," that the fuel oil aging management program is in part based on the fuel oil purity and testing requirements of the plant's Technical Specifications. XI.M30 further refers to the Standard Technical Specifications of NUREG-1430 through NUREG-1433. TMI-1 has not adopted the Standard Technical Specifications as described in these NUREGs; however, the TMI-1 fuel oil specifications and procedures invoke requirements for Emergency Diesel Generator fuel oil purity and fuel oil testing that ensure that the intended function of fuel oil systems and components will be maintained during the period of extended operation.

Standard Technical Specification Section 5.5.13 in NUREG-1430 establishes testing requirements for emergency diesel generator fuel oil to determine the acceptability of new fuel oil for use prior to addition to storage tanks. The testing requirements verify that the fuel oil has a) an API gravity <u>or</u> an absolute specific gravity within limits, b) a flash point <u>and</u> kinematic viscosity within limits for No. 2 fuel oil, and, c) a clear and bright appearance with proper color <u>or</u> a water and sediment content within limits. The TMI-1 Fuel Oil Chemistry aging management program meets these requirements by establishing the acceptability of new fuel oil for use prior to its addition to storage tanks by determining that API gravity, flash point, kinematic viscosity, and water and sediment content are within limits.

Standard Technical Specification Section 5.5.13 establishes testing requirements for emergency diesel generator fuel oil to confirm the acceptability of the new fuel oil following its addition to storage tanks. The testing requirements verify within 31 days that the properties of the new fuel oil, other than those addressed above, are within limits for No. 2 fuel oil. The TMI-1 Fuel Oil Chemistry aging management program meets these requirements by requiring, within 31 days of its addition to storage tanks, a complete No. 2 fuel oil analysis consisting of API gravity, flash point, cloud point, kinematic viscosity, distillation temperature, carbon residue, sulfur, copper strip corrosion, ash, total insolubles, cetane number, water and sediment, and red dye to confirm that the new fuel oil is within limits for No. 2 fuel oil.

The Standard Technical Specification 5.5.13 establishes testing requirements for emergency diesel generator fuel oil to determine the acceptability of stored fuel oil. The testing requirements verify that the total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days. TMI-1 meets the requirement for particulate concentration limits (≤ 10 mg/l) but performs this test at a frequency of every 91 days. TMI-1 operating experience has demonstrated the acceptability of the 91-day frequency. This frequency is also in accordance with NUREG-1801 XI.M30, Element 5 "Monitoring and Trending" which states that "based on industry operating experience, quarterly sampling and analysis of fuel oil provides for timely detection of conditions conducive to corrosion of the internal surface of the diesel fuel oil tank before the potential loss of its intended function."

RAI#: B.2.1.16-2

LRA Section: B.2.1.16, Fuel Oil Chemistry

Background:

On page B-60 of the LRA it is stated that multilevel sampling, tank bottom draining, cleaning and internal inspection of the 7.3 gallon Station Blackout Diesel Clean Fuel Tank and the 550 gallon Station Blackout Diesel Fuel Day Tank are not periodically performed.

Issue:

In page B-60 of the LRA it is stated that a one-time inspection will be performed for these tanks. On page B-62 of the LRA it is stated that and enhancement will be the use of ultrasonic techniques for determining tank bottom thicknesses should there be any evidence of loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, and fouling found during visual inspection activities.

Request:

1. Provide the reason that these tanks can not be periodically drained, cleaned, and periodically inspected.
2. Provide the scope of UT examination of the tank bottoms.
3. Provide the design features of the tanks.
4. Explain how a one-time UT is equivalent to periodic draining, cleaning, and inspection.

AmerGen Response

1. The 550 gallon DF-T-7 SBO diesel fuel oil day tank and the 7.3 gallon DF-T-9 SBO diesel clean fuel oil tank are not provided with design features, such as manholes or hatches, that allow these tanks to be readily cleaned and internally inspected. Access to the internal of the tank for cleaning or inspection cannot be accomplished without the removal of piping, fittings, or instrumentation attached to the top, sides, or bottom of the tanks.

2. The exteriors of the 550 gallon DF-T-7 SBO diesel fuel oil day tank and the 7.3 gallon DF-T-9 SBO diesel clean fuel oil tank are readily accessible. The one-time external volumetric examination will include the tank bottoms using a grid based on standard NDE practices. Internal VT examination may be substituted for external volumetric examination if the opportunity for internal inspection presents itself. Should VT examination identify the loss of material, volumetric examination will be used to determine tank bottom thickness.

3. Neither the 550 gallon DF-T-7 SBO diesel fuel oil day tank nor the 7.3 gallon DF-T-9 SBO diesel clean fuel oil tank are provided with design features, such as manholes or hatches, that allow access to the internal of the tank for multilevel sampling, cleaning, or inspection. Access to the internal of the tank for multilevel sampling, cleaning, or inspection cannot be accomplished without the removal of piping, fittings, or instrumentation attached to the top, sides, or bottom of the tanks.

4. Aging effects in the 550 gallon DF-T-7 SBO diesel fuel oil day tank and the 7.3 gallon DF-T-9 SBO diesel clean fuel oil tank are expected to be insignificant because these tanks are integral to the routine operation of the Station Blackout Diesel and are filled with fuel oil that has been previously analyzed within the managed fuel oil source tank, the DF-T-8 Station Blackout Diesel Fuel Storage Tank. In addition, the fuel oil within the DF-T-7 SBO diesel fuel oil day tank is recirculated to the DF-T-8 Station Blackout Diesel Fuel Storage Tank quarterly to prevent the accumulation of contaminants and water and sediment. The DF-T-9 SBO diesel clean fuel oil tank experiences a turnover of the fuel collected within as a result of routine engine operation preventing the accumulation of contaminants and water and sediment.

   The one-time inspection confirms that either the aging effect is not occurring, or the aging effect is occurring very slowly so that the tanks' intended function is not affected during the period of extended operation. Should the one-time inspection reveal evidence of an aging effect, this finding will be entered into the corrective action process for the identification of additional actions that will assure that the intended function of these tanks will be maintained during the period of extended operation.

RAI#: B.2.1.16-3

LRA Section: B.2.1.16, Fuel Oil Chemistry

Background:

On page B-60 of the LRA it is stated that the GALL Report requires periodic multilevel sampling of tanks in accordance with the manual sampling standards of American Society for Testing and Materials (ASTM) D 4057-95 (2000).

Issue:

TMI-1 has not committed to ASTM D 4057-95 (2000) for manual sampling standards. Instead, samples are taken near the bottom of the tank where water and particulate and water concentrations will be larger due to settlement. However, it is not clear why multilevel sampling of these tanks can not be performed.

Request:

Explain why multilevel sampling of tanks cannot be performed and why it is believed that bottom sampling is equivalent to multilevel sampling.

AmerGen Response

TMI-1 has not committed to ASTM D 4057-95 (2000) for manual sampling standards for the FO-T-3 and FO-T-4 diesel fire pump fuel oil tanks, the DF-T-2A and DF-T-2B emergency diesel generator fuel oil day tanks, and the FO-T-1 fuel oil storage tank.

The FO-T-3 and FO-T-4 diesel fire pump fuel oil tanks are 350-gallon horizontal cylindrical tanks. These tanks are not provided with design features such as manholes or hatches that allow access to the internal volume of the tank for multilevel sampling. Access to the internal of the tank for multilevel sampling cannot be accomplished without the removal of the tanks from service and the removal of piping, fittings, or instrumentation attached to the top of the tanks. The FO-T-3 and FO-T-4 diesel fire pump fuel oil tank samples are single point samples obtained from the tank drain line located off of the bottom of the tank. This sample is not considered "equivalent" to a multilevel sample as described in ASTM D 4057; however, the lower sample elevation is more likely to contain contaminants and water and sediment which tend to settle in the tank, thus making this a conservative and effective sampling location for fuel oil contaminants. Operating experience has shown that this sample method has yielded consistently acceptable sample results.

The DF-T-2A and DF-T-2B emergency diesel generator fuel oil day tanks are 550-gallon horizontal cylindrical tanks. These tanks are not provided with design features such as manholes or hatches that allow access to the internal volume of the tank for multilevel sampling. Access to the internal of the tank for multilevel sampling cannot be accomplished without the removal of the tanks from service and the removal of piping, fittings, or instrumentation attached to the top of the tanks. The DF-T-2A and DF-T-2B emergency diesel generator fuel oil day tank samples are single point samples obtained from the tank drain line located off of the bottom of the tank. This sample is not considered "equivalent" to a multilevel sample as described in ASTM D 4057; however, the lower sample elevation is more likely to contain contaminants and water and sediment which tend to settle in the tank, thus making this a conservative and effective sampling location for fuel oil contaminants. Operating experience has shown that this sample method has yielded consistently acceptable sample results.

The FO-T-1 fuel oil storage tank is a 50,000-gallon vertical cylindrical tank measuring 22' in diameter and 17'-9" in height. The tank roof includes a 24" diameter manhole to gain access to the tank interior and a 4" diameter gauge hatch for permitting inspection and entry for gauging or sampling. Access to the top of the tank is available by a ladder and platform. Although design features exist which allow access to the top of the tank for multilevel sampling, there are industrial safety issues inherent to weekly multilevel sampling through the roof manhole or gauge hatch. In lieu of this, sampling of the tank is performed through a sample connection off of the tank outlet after recirculating the tank contents, which promotes tank mixing and purging of the recirculation and sample piping. This sample is not considered "equivalent" to a multilevel sample as described in ASTM D 4057; however, the sample draw off location at the tank outlet is more likely to contain contaminants and water and sediment which tend to settle in the tank, thus making this a conservative and effective sampling location for fuel oil contaminants. Operating experience has shown that this sample method has yielded consistently acceptable sample results.

RAI#: B.2.1.16-4

LRA Section: B.2.1.16, Fuel Oil Chemistry

Background:

Results of cleaning and visual inspection of fuel oil tanks was not available.

Issue:

The staff's review of documents provided by the applicant during the onsite audit did not include results of cleaning and visual inspection of fuel oil tanks.

Request:

Provide information documenting fuel oil tank cleaning and visual inspection to confirm that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

AmerGen Response

A review of site records was performed to identify internal inspections of TMI-1 fuel oil tanks managed by the Fuel Oil Chemistry aging management program. With the exception of the 50,000-gallon FO-T-1 fuel oil storage tank, no other fuel oil tanks managed by the Fuel Oil Chemistry aging management program were identified to have been cleaned and internally inspected.

The FO-T-1 fuel oil storage tank is a 50,000-gallon vertical cylindrical tank measuring 22' in diameter and 17'-9" in height designed and constructed to American Petroleum Institute (API) Standard 650, "Welded Steel Tanks for Oil Storage." Floor plates are constructed with ASTM A283C carbon steel plate.

In September 2007, an internal inspection of the 50,000-gallon FO-T-1 fuel oil storage tank was conducted in conformance with the specifications in API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction." The purpose of the inspection was to assess the condition of the tank and determine its compliance with applicable regulations and industry codes, as well as suitability for continued use. This was the first and only time that an internal inspection of the 50,000-gallon FO-T-1 fuel oil storage tank was conducted.

The September 2007 inspection did not reveal any degradation not bounded by industry experience or identified in the TMI-1 License Renewal Application for carbon steel exposed to a fuel oil internal environment. The following observations were noted during the inspection:

- The tank floor showed some visual signs of minor pitting and general surface corrosion, which did not require repair.

- There were two (2) additional areas that had severe pitting corrosion on the surface of the floor. The pits, although small in diameter, were fairly deep, down to about ½ to ¾ of the way through the floor plates. These areas were repaired in accordance with API

Standard 653 by welding patch plates over the affected areas. The repairs were visually inspected and vacuum box tested.

Based on the information obtained during the inspection, the life expectancy of the tank was judged by the API 653 certified/Pennsylvania Department of Environmental Protection certified Inspector to be "well over twenty years." The enhanced Fuel Oil Chemistry aging management program provides for cleaning and internal inspection of this fuel oil tank on a frequency of every 10 years to ensure its intended function during the period of extended operation.

RAI#: B.2.1.20-1

Background:

The staff noted that UT examination is capable of detecting loss of material in buried fuel oil tanks.

Issue:

The LRA is not clear as to the extent and scope of the UT examinations. The potential for degradation of a buried tank is uniform over the entire surface of the tank. Measurements of tank thickness representative of the entire tank surface needs to be performed to ensure that the tank will continue to perform its intended function.

Request:

Provide additional information that identifies the extent and scope of the UT measurements of the buried Diesel Generator Fuel Storage 30,000 Gallon Tank.

AmerGen Response

The Diesel Generator Fuel Storage 30,000 Gallon Tank will be internally inspected in accordance with the guidance for assessing tank wall thickness contained in American Petroleum Institute (API) Standard 1631, "Interior Lining and Periodic Inspection of Underground Storage Tanks." A visual inspection of the entire internal surface will be performed. For the UT measurements, per the guidance in API 1631, the internal tank wall will be divided into 3 foot square sections. The UT measurement will be taken at the center of each section. Should the results of the UT wall thickness measurement for any section be 75 percent or less of the original wall thickness, the scope of inspection is expanded by further subdividing that section into 9 one-foot square subsections and UT measurements will be taken at the center of each subsection. The average of the results taken at the 9 locations is then used to ascertain the wall thickness condition of the section. Results not satisfying the acceptance criteria are evaluated and a condition report is initiated to document the concern in accordance with plant administrative procedures.

<u>RAI#: B.2.1.21-1</u>

LRA Section: External Surfaces Monitoring

Background:

On page B-77 of the LRA under "Exceptions" it is stated that the scope of the materials to be inspected by the program will be expanded to include aluminum alloy, asbestos cloth, copper alloy, elastomers and stainless steel. The exception further states that the scope of aging effects will also be expanded to include hardening and loss of strength.

Issue:

The GALL Report AMP XI.M36 states that the External Surfaces Monitoring Program is only applicable to detect loss of material due to general, pitting, and crevice corrosion for carbon steel components only.

Request:

1. Justify the basis for including aluminum alloy, copper alloy, and stainless steel in the scope of AMP B.2.1.21 and explain how this program will adequately manage the aging effects of loss of material as it applies to the additional metallic components added to the scope of the program.

2. Justify the basis for including elastomers in the scope of AMP B.2.1.21 and explain how this program will adequately manage the aging effects of hardening and loss of strength as it applies to the additional non-metallic components added to the scope of the program. Describe the specific inspection techniques that will be used to detect the applicable aging effects for elastomers and clarify the acceptance criteria that will be used for these inspection techniques.

3. In Table 3.2.2-04 on page 3.2-68 of the LRA, AMP B.2.1.21 is credited for managing loss of material due to cracking for asbestos. Clarify whether this aging effect is in the scope of this program for asbestos. Justify how this program will adequately manage loss of material due to cracking for asbestos or provide an appropriate program to manage loss of material due to cracking for asbestos.

<u>AmerGen Response</u>

1. NUREG-1801 AMP XI.M36, External Surfaces Monitoring program is recommended for managing loss of material on the external surfaces of carbon steel components. The TMI-1 External Surfaces Monitoring program, B.2.1.21 includes loss of material on the external surfaces of carbon steel components as well as aluminum alloy, copper alloy, and stainless steel components because visual inspections performed during system walkdowns can adequately identify and manage loss of material for these additional material types.

   The parameters monitored during the system walkdowns include:

   - Corrosion and corrosion byproducts

- Coating degradation (e.g.; blistering and peeling)
- Discoloration
- Scale/deposits
- Pits
- Surface discontinuities

The program provides qualification requirements for personnel performing visual inspection activities and they are in accordance with site controlled procedures and processes; therefore, the program is capable of managing loss of material for the additional material types of aluminum alloy, copper alloy, and stainless steel.

2. Hardening and loss of strength of elastomers can be detected via visual inspections that are performed during system walkdowns. The inspection will look for cracking and flaking. A resiliency test will also be performed by compressing the material and observing a return to the original shape.

3. The External Surfaces Monitoring program manages loss of material due to cracking of asbestos cloth expansion joints in the Primary Containment Heating and Ventilation System. Visual inspections performed during system walkdowns can adequately identify and manage loss of material due to cracking of the asbestos cloth by inspecting for cracked or missing material.

RAI#: B.2.1.22-1

LRA Section: B.2.1.22, Inspection of Internal Surfaces in Misc. Piping and Ducting Components

Background:

On page B-79 of the LRA, under the "exceptions", it is stated that the scope of the materials to be inspected by the program will be expanded to include asbestos, copper alloy with 15% zinc or more, copper alloy with less than 15% zinc, neoprene, nickel alloy, rubber, stainless steel and titanium alloy. The exception further states that the scope of aging effects will also be expanded to include cracking, reduction of heat transfer, hardening and loss of strength.

Issue:

The GALL Report AMP XI.M38 states that the material within the scope of this program is limited to only steel and for visual inspections to detect visual evidence of corrosion to indicate possible loss of material.

Request:

1. Justify the basis for including copper alloy with 15% zinc or more, copper alloy with less than 15% zinc, nickel alloy, stainless steel and titanium in the scope of AMP B.2.1.22 and explain how this program will adequately manage the aging effects of loss of material and reduction of heat transfer as it applies to the additional metallic components added to the scope of the program.

2. Justify the basis for including neoprene and rubber in the scope of AMP B.2.1.22 and explain how this program will adequately manage the aging effects of hardening and loss of strength as it applies to the additional non-metallic components added to the scope of the program. Describe the specific inspection techniques that will be used to detect the applicable aging effects for elastomers and clarify the acceptance criteria that will be used for these inspection techniques.

3. In Table 3.2.2-04 on page 3.2-68 of the LRA, AMP B.2.1.22 is credited for managing loss of material due to cracking for asbestos. Clarify whether this aging effect is in the scope of this program for asbestos. Justify how this program will adequately manage loss of material due to cracking for asbestos or provide an appropriate program to manage loss of material due to cracking for asbestos.

4. On page B-79 of the LRA in section B.2.1.22 under exceptions to the Gall Report, it is stated that stress corrosion cracking (SCC) of stainless steel components will be detected by the use of volumetric testing. Please clarify the acceptance criteria that will be used for the volumetric testing to detect SCC of stainless steel components.

AmerGen Response

1. NUREG-1801 AMP XI.M38, Internal Surfaces in Miscellaneous Piping and Ducting Components program is recommended for managing loss of material on the internal surfaces of carbon steel components. The TMI-1 Internal Surfaces in Miscellaneous Piping and Ducting Components program, B.2.1.22 includes loss of material on the

internal surfaces of carbon steel components as well as copper alloy, nickel alloy, stainless steel, and titanium components because visual inspections performed during the inspections can adequately identify and manage loss of material in these additional materials types.

The parameters monitored during the inspections include:

- Corrosion and corrosion byproducts
- Coating degradation (e.g.; blistering and peeling)
- Discoloration
- Scale/deposits
- Pits
- Surface discontinuities

The program provides qualification requirements for personnel performing visual inspection activities and they are in accordance with site controlled procedures and processes; therefore, the program is capable of managing loss of material for the additional material types of copper alloy, nickel alloy, stainless steel, and titanium.

The external surfaces of cooling coils will be cleaned and inspected for fouling, which could cause reduction of heat transfer. These inspections will be performed at the same time as the internal surfaces inspection of the associated components.

2. The basis for including elastomers in the External Surfaces Monitoring program is hardening and loss of strength of elastomers can be detected via visual inspections on the internal surfaces of elastomer components. The inspection will look for cracking and flaking. A resiliency test will also be performed by compressing the material and observing a return to the original shape.

3. The Internal Surfaces in Miscellaneous Piping and Ducting Components program manages loss of material due to cracking of asbestos cloth expansion joints in the Primary Containment Heating and Ventilation System. Visual inspections performed on the internal surfaces of the expansion joints can adequately identify and manage loss of material due to cracking of the asbestos cloth by inspecting for cracked or missing material.

4. Any cracking of stainless steel components identified by ultrasonic testing will be entered into the corrective action process and evaluated. Evaluations are performed for test or inspection results that do not satisfy acceptance criteria and a condition report is initiated to document the concern in accordance with plant administrative procedures that meet the requirements of 10 CFR Part 50, Appendix B. Corrective action steps are taken as required.

RAI#: B.2.1.22-2

LRA Section: B.2.1.22, Inspection of Internal Surfaces in Misc. Piping and Ducting Components

Background:

On page B-80 of the LRA in the operating experience section of AMP B.2.1.22, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components", it is stated that an internal inspection is performed during each refueling outage of the Reactor Building Cooling Units at specified locations.

Issue:

On page B-80, the LRA further states that boron deposits coating less than 5% of the total surface area of the normal cooling coils were found. Corrective actions were taken by the applicant to clean the boron deposits on the fan and coolers, and the reactor coolant leak was fixed.

Request:

Please describe the results of the internal inspections subsequent to the discovery of boron deposits during the 2003 refueling outage and clarify whether or not the existing procedures are suitable for managing age-related degradation in this system that would otherwise impact the components intended function during the period of extended operation.

AmerGen Response

Inspections and cleaning of the Reactor Building air-handling units are routinely performed on a two-year frequency. As stated in LRA Section B.2.1.22, the 2003 inspections identified some degradation (boric acid corrosion followed by general corrosion) associated with the structural supports of these air-handling units. Based on external and internal assessments and nondestructive examination results, the corrosion is within acceptable limits. The two inspections performed since 2003 have identified negligible boron deposits that have resulted in no significant material loss. No significant material degradation has been identified on the cooling coils or air-handling unit housings. Continued monitoring and trending of inspection results will ensure that loss of intended function will not occur.

Material conditions of the cooling coils, supports, and air-handling unit housings are evaluated in accordance with existing procedures. Adverse material conditions are entered into the corrective action program before loss of intended function can occur. The existing procedures are adequate to manage age-related degradation (i.e., loss of material and reduction of heat transfer) during the period of extended operation.

RAI#: B.2.1.22-3

LRA Section: B.2.1.22, Inspection of Internal Surfaces in Misc. Piping and Ducting Components

Background:

On page B-79 of the LRA under "Exceptions" it is stated that physical manipulation may be used to detect hardening and loss of strength of elastomers both internally and externally.

Issue:

On page B-79 under the program description, on page A-17 in the summary description for Section A.2.1.22, and in Commitment #22 on page A-46 there is no mention of augmenting a visual inspection with a physical manipulation to detect hardening and loss of strength of elastomers.

Request:

Clarify whether or not a brief description of augmenting visual inspections with a physical manipulation for elastomers should be included in the program description of LRA Section B.2.1.22, the summary description in LRA Section A.2.1.22 and Commitment #22.

AmerGen Response

Visual inspections of elastomers performed under the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program are augmented by physical manipulation. Section A.2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components changes as follows:

> The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new program that manages cracking due to stress corrosion cracking; hardening and loss of strength due to elastomer degradation; loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling; and reduction of heat transfer due to fouling. ***Visual inspections may be augmented by physical manipulation to detect hardening and loss of strength of elastomers.*** The program includes provisions for visual inspections of the internal surfaces and volumetric testing of components not managed under any other aging management program. Identified deficiencies are evaluated under the Corrective Action Program. This new aging management program will be implemented prior to the period of extended operation.

The Commitment for Item Number 22 in LRA Section A.5, License Renewal Commitment List changes as follows:

Program is new. The program will be used to manage cracking due to stress corrosion cracking; hardening and loss of strength due to elastomer degradation; loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling; and reduction of heat transfer due to fouling. The program includes provisions for visual inspections of the internal surfaces and volumetric testing of components not managed under any other aging management program. ***Visual inspections may be augmented by physical manipulation to detect hardening and loss of strength of elastomers.***

Section B.2.1.22, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components changes as follows:

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new program that provides for managing cracking due to stress corrosion cracking; hardening and loss of strength due to elastomer degradation; loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, cracking, and fouling; and reduction of heat transfer due to fouling. The program includes provisions for visual inspections of the internal surfaces and volumetric testing of components not managed under any other aging management program and initiate corrective action. ***Visual inspections may be augmented by physical manipulation to detect hardening and loss of strength of elastomers.*** The program also includes inspection of the external surfaces of expansion joints in ducting.

RAI #: B.3.1.1-1

LRA Section: B.3.1.1, Metal Fatigue of Reactor Coolant Pressure Boundary

Background:

The TMI-1 metal fatigue of reactor coolant pressure boundary management program relies on transient cycle monitoring to evaluate the fatigue usage described in the license renewal application. This approach tracks the number of occurrences of significant thermal and pressure transients (significant events) and compares the cumulative cycles, projected to cover the renewal period, against the number of design cycles specified in the design specifications. The projected cycles are then used to evaluate the total cumulative usage factor (CUF) which covers the period of extended operation. For this approach to work, none of the significant events tracked should produce stresses greater than those that would be produced by the design transients. That is, the P-T (Temperature and Pressure) characteristics, including their values, ranges, and rates, all must be bounded within those defined in the design specifications.

Issue:

Based on a review of the LRA, the LRA does not require the P-T characteristics, including their values, ranges, and rates be bounded within the characteristics defined in the design specifications.

Request:

Please provide additional information so the staff can confirm that the program will ensure that P-T characteristics, including their values, ranges, and rates remain bounded within the characteristics defined in the design specifications.

AmerGen Response

In order to assure that the tracked events do not produce stresses greater than those produced by the design transients, the plant fatigue monitoring procedure provides detailed design transient descriptions and bases for review by Control Room Operators during the logging of a transient. These definitions characterize each monitored design transient event. In addition, the monitoring procedure references supporting documents that provide guidance for transient logging and data collection for the defined transients.

Individual operational procedures (associated with particular operational events, such as heatups and cooldowns) include steps to review transient cycle logging requirements in preparation for a planned operational event. This includes a requirement to ensure all appropriate log entries for evolutions and events that occurred during the operational event have been entered into the Transient Cycle Logbook.

The corporate fatigue monitoring procedure requires the Fatigue Monitoring Engineer to review the plant operating logs semiannually and whenever an unusual reactor operating event occurs that would require abnormal coolant injections to occur. During the semiannual review, the Fatigue Monitoring Engineer is required to identify the thermal transients that have occurred since the last fatigue monitoring cycle count was documented and to determine the operational transient event that best describes it, using the design basis descriptions of the operational transient events. The changes in plant and/or system process parameters (e.g. pressure, temperature, and flow rate) for the design basis operational transient must bound the thermal transient event parameter changes. Plant logs and instrument data from the plant computer are used if necessary to assure that the actual transients have been appropriately characterized and that the design transients bound them. The review also requires verification that the total number of transients experienced does not exceed the design number of cycles and requires notification of the Engineering Program Manager if 80% of a design limit is being approached.

If the plant and/or system process parameters are not bounded by a design basis operational transient, the Fatigue Monitoring Engineer is required to notify the Engineering Program Manager, initiate an action in the Corrective Action Program to perform an engineering evaluation of the condition, and determine the required corrective action.

Enclosure B

SUMMARY OF REGULATORY COMMITMENTS

The following table identifies commitments made in this document. (Any other actions discussed in the submittal represent intended or planned actions. They are described to the NRC for the NRC's information and are not regulatory commitments.)

COMMITMENT	COMMITTED DATE OR "OUTAGE"	COMMITMENT TYPE	
		ONE-TIME ACTION (Yes/No)	PROGRAMMATIC (Yes/No)
Fire Protection Program (RAI # B.2.1.13-1) Existing program is credited. The program will be enhanced to include additional inspection criteria for degradation of fire barrier walls, ceilings, and floors, and specific fuel supply line inspection criteria for diesel-driven fire pumps during tests. ***In addition, implementing surveillance procedures for halon and carbon dioxide suppression systems will specifically require inspection for corrosion, mechanical damage, or damage to dampers, and will include acceptance criteria stating that detected signs of corrosion or mechanical damage be evaluated, with corrective action taken as appropriate.***	Prior to the Period of Extended Operation	No	Yes
Fire Protection Program (RAI # B.2.1.13-2) Existing program is credited. The program will be enhanced to include additional inspection criteria for degradation of fire barrier walls, ceilings, and floors, and specific fuel supply line inspection criteria for diesel-driven fire pumps during tests. ***In addition, implementing surveillance procedures for halon and carbon dioxide suppression systems will specifically require inspection for corrosion, mechanical damage, or damage to dampers, and will include acceptance criteria stating that detected signs of corrosion or mechanical damage be evaluated, with corrective action taken as appropriate.***	Prior to the Period of Extended Operation	No	Yes

Enclosure B

SUMMARY OF REGULATORY COMMITMENTS (continued)

Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (RAI B.2.1.22-3) The Commitment for Item Number 22 in LRA Section A.5, License Renewal Commitment List changes as follows: Program is new. The program will be used to manage cracking due to stress corrosion cracking; hardening and loss of strength due to elastomer degradation; loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and fouling; and reduction of heat transfer due to fouling. The program includes provisions for visual inspections of the internal surfaces and volumetric testing of components not managed under any other aging management program. ***Visual inspections may be augmented by physical manipulation to detect hardening and loss of strength of elastomers.***	Prior to the Period of Extended Operation	No	Yes